Regulations – Appendix

1. United States – Federal Fugitive Methane Emission Regulations

1.1 Environmental Protection Agency

1.1.1 New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector Subpart OOOOa [Citation: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942]

EPA's NSPS Subpart OOOOa ("NSPS OOOOa"), which is a revision to NSPS OOOO, became effective on August 2, 2016 and applies to facilities in the drilling, production and processing segments of the onshore oil and gas sector that commenced construction, modification or reconstruction after September 18, 2015. As of the publication of this document, the status of NSPA OOOOa, particularly in regard to the leak detection and repair (LDAR) requirements for fugitive emissions, is uncertain (*note here or reference to current status).* However, a summary of the LDAR requirements as they currently stand will be provided.

NSPA OOOOa regulates methane and VOCs from a variety of sources, including fugitive emissions. NSPA OOOOa also includes a provision for approval of emerging or alternative technologies for fugitive emissions detection. The summary below provides an overview of the fugitive emissions/LDAR and emerging technology sections of the rule.

[Note: On July 3, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated EPA's 90-day stay of portions of the 2016 New Source Performance Standards for the Oil and Gas Industry which included the LDAR provisions. EPA is considering its options in light of the court's opinion. On July 7, 2017, EPA moved the court to recall its mandate in order to provide EPA with the standard short period of time in which to evaluate its options before the court's decision becomes effective. This motion is pending before the court. The court also emphasized that nothing in its opinion limits EPA's authority to reconsider the oil and gas standards and to proceed with its June 16, 2017 proposed two-year stay of certain requirements in the rule (including LDAR). EPA will take comment on those proposals until August 9, 2017.]

On July 13, 2017, the U.S. Court of Appeals for the D.C. Circuit ordered a recall for 14 days its decision vacating the stay of EPA's June 3, 2016 final rule establishing New Source Performance Standards for the oil and natural gas industry (81 Fed. Reg. 35,824) on July 3. The recall was in response to EPA's July 7 motion, which asked the court to recall the ruling in order to give EPA time to "determine whether to seek panel rehearing, rehearing en banc, or pursue other relief."

Clean Air Council v. Environmental Protection Agency, No. 17-1145, July 3, 2017 (United States Court of Appeals for the District of Columbia Circuit)

Commented [BC1]: Susan et al – Here's the most recent statement from EPA on the status of the Administrator's stay on certain provisions of NSPS OOOOa which include LDAR requirements. I don't know how we want to reflect this in final doc – TBD.

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Commented [TTA3]: Let's keep a separate record or document with the current status of the rule that can be updated as time goes on while we're still working to finalize our Tech-Reg doc. I've created a placeholder for the current status of the rule in the introductory paragraph for OOOOa.

NSPS Subpart OOOOa Requirements for Fugitive Emissions **Footnote here Fed Reg**

NSPS OOOOa imposes standards to control GHGs (in the form of limitations on methane emissions) and VOC emissions from fugitive emission components at well sites (including centralized tank batteries) and compressor stations (gathering & boosting as well as transmission

& storage). Semiannual or quarterly monitoring and repair of equipment and components that may leak or release fugitive emissions at these facilities is required.

Leak monitoring must be conducted using optical gas imaging (OGI), which is often referred to as an infrared (IR) camera, and repairs must be made if any emissions are seen or observed. EPA determined OGI, which can see emissions not visible to the naked eye, to be what is known as the Best System of Emissions Reduction (BSER) for fugitive emissions from well sites and compressor stations, which means OGI meets the standard of performance established by EPA for achieving the necessary emission reductions at these facilities. However, OOOOa also allows that Method 21 (M21), which detects leaks and indicates their size as a concentration level in air in parts per million (ppm), may be used as an alternative monitoring method to OGI, which can only detect emissions. If M21 is used, then component repair must be conducted if the leak concentration level is 500 ppm or greater. Repairs must be made within 30 days of finding fugitive emissions and a resurvey of the repaired component must be made within 30 days of the repair using OGI or M21 at a repair threshold of 500 ppm. Monitoring and repair records must be maintained and submitted with semi-annual reports to EPA or the delegated authority.

If OGI is used, a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company-defined area must be developed and implemented. Owners and operators develop a plan that describes the facilities subject to monitoring in that area, including descriptions of equipment, plans for how monitoring will be conducted, etc., that apply to all similar facilities. This allows owners and operators to develop a monitoring plan for groups of similar facilities within an area for ease of implementation and compliance. These plans must include a typical "observation path" that is focused on the field of view of the OGI instrument being used(not the physical location of the OGI operator) to ensure all components get monitored. The intent is to allow for the use of all types of OGI instruments (e.g., mounted, handheld or remote controlled) for monitoring. The observation path description may be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI instrument's monitoring path.

ADD PARAGRAPH HERE THAT ADDRESSES OOOOa's "MINIMUM DETECTION DISTANCE" THRESHOLD FOR OGI.

For a rule to be enforceable, besides the monitoring stipulated, there must also be transparent recordkeeping and annual reporting that tracks leaks, repairs and resurveys.

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Provision for Emerging Technology

Fugitive emissions monitoring and repair is a work practice standard, as allowed under the Clean Air Act (CAA) *(reference here)*. A work practice standard is an emission limitation (BSER) that is not necessarily in a numeric format, such as the visualization of fugitive emissions using OGI. The Clean Air Act also allows approval an alternative means of emission limitation (AMEL) for a work practice standard if it can be proven that an equal reduction in emissions will be achieved through that alternative *(reference here – NSPS 111(h)(3))*. To that end, and because methane and VOC leak detection technology has been undergoing continuous and rapid development and innovation, potentially yielding, for example, continuous emissions monitoring technologies, NSPS OOOOa includes a process for EPA to permit the use of an innovative technology for reducing fugitive emissions at well sites and/or compressor stations *(reference here)*.

Specifically, *owners or operators* may submit a request to the EPA for an "alternative means of emission limitation" where a technology has been demonstrated to achieve a reduction in emissions at least equivalent to the reductions achieved under the OGI work practice of NSPS OOOOa.

To facilitate the application and review process, NSPS OOOOa identifies information that must be included in the AMEL application in order for EPA to evaluate the emerging technology, which includes:

- a description of the emerging technology and the associated monitoring instrument or measurement technology;
- a description of the method and data quality used to ensure the effectiveness of the technology;
- a description of the method detection limit of the technology and the action level at which fugitive emissions would be detected;
- a description of the quality assurance and control measures employed by the technology;
- field data (covering a period of at least 12 months and contemporaneously conducting M21 or OGI leak detection at prescribed frequency) that verify the feasibility and detection capabilities of the technology; and
- any restrictions for using the technology.

This process allows for the approval and use of any work practice developed in the future that can demonstrate methane and VOC emission reductions at levels that are at least equivalent to the reductions achieved when using OGI or M21 for fugitive emissions monitoring. This process also allows for the use of alternative fugitive emissions mitigations approaches utilizing periodic, continuous, fixed, and mobile (including aerial), or hybrid monitoring approaches.

Consistent with the AMEL provision of the CAA, any application will be publicly noticed in the Federal Register, including all required information for evaluation. The EPA will provide an opportunity for public hearing and comment on the application and on intended action the EPA might take. The EPA then makes a final determination on the AMEL application within six months after the close of the public comment periodand publishes its determination in the Federal Register. If the final determination is denial of the application, the EPA will provide reasoning for denial and recommendations for further development and evaluation of the emerging technology, if appropriate. If an AMEL is granted approval, then it is specific to a single facility and applicant *(Cindy – need clarification on this)*.

Note that in order for a technology to be considered for AMEL under OOOOa it must be capable of detecting methane and VOCs, or be able to demonstrate equivalent reductions of methane and VOCs if not all compounds can be detected.

As of the date of this document, EPA had not received any AMEL applications under OOOOa.

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Citation: Federal Register Vol. 81, No. 107, 6/3/16. 35824-35942 [cite again here? – how much of the text above is directly copies and needing a citation?]

1.1.2 Greenhouse Gas Mandatory Reporting Rule

The Greenhouse Gas Mandatory Reporting Rule (also known as the Greenhouse Gas Reporting Program or GHGRP) was published by EPA in October 2009 and went into effect in January 2010. The rule requires annual reporting of greenhouse gases (GHG), including methane, from large emission sources across a range of industrial categories, including the oil and gas sector. The purpose of the rule, as noted by EPA *(*[HYPERLINK "https://www.epa.gov/sites/production/files/2014-09/documents/ghgrp-overview-factsheet.pdf"]*)*, is to provide for a "collection of comprehensive, nationwide emissions data [that] is intended to provide a better understanding of the sources of GHGs and to guide development of policies and programs to reduce emissions." Thus, unlike NSPS OOOOa, actual emission reductions are not required under GHGRP, only calculation and reporting of emissions. Additionally, VOCs are not covered under GHGRP since they are not GHGs.

One of the options in GHGRP for estimating emissions from equipment leaks ("fugitive emissions") in the oil and gas sector is an equipment leak survey. Equipment leak surveys are required for certain component types, and reporters must use one of the monitoring methods specified in the rule to conduct those surveys. In recent revisions to the rule, effective January 1, 2017 *(reference here)*, new monitoring methods for detecting leaks from equipment in the petroleum and natural gas source category were added to be consistent with the leak detection methods in the New Source Performance Standards (NSPS) for the oil and gas industry. These revisions were the result of a review of existing requirements in the GHGRP to address potential gaps in coverage and to improve monitoring methods to ensure high quality data reporting. EPA also received direction to explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions in the oil and gas sector.

Subpart W of the GHGRP specifies the monitoring methods that may be used for equipment leak surveys, which include Optical Gas Imaging, Method 21, Infrared Laser Illuminated Instruments and Acoustic Leak Detection Devices. The rule specifies how leaks are to be measured for each monitoring method used. Additionally, Subpart W allows for temporary use of alternative monitoring methods not specified in the rule for certain facilities and operations.

1.1.3 Alternative Work Practice (AWP) to Method 21 for Leak Detection and Repair

Numerous EPA air emissions standards, including those for segments of the oil and gas sector, require a specific work practice (NSPS VV & VVa) that identifies Method 21 for equipment leak detection and repair (LDAR) of fugitive VOC emissions. On April 6, 2006, the EPA proposed a voluntary alternative work practice (AWP) for LDAR using optical gas imaging (OGI), which was a newly developed technology at the time, The AWP was eventually finalized and adopted in 2008 and allows for the voluntary use of OGI in place of Method 21 for any rule that requires

LDAR for fugitive VOCs. The AWP still requires annual monitoring using Method 21 but all other periodic monitoring may be performed with OGI.

Note that in NSPS OOOOa, OGI and/or Method 21 is the allowed work practice for LDAR at well sites and compressor stations. However, for gas processing plants subject to OOOOa, OGI is still considered the AWP for purposes of LDAR and Method 21 is the required work practice.

The AWP was the first time EPA allowed an alternative to Method 21 for LDAR and, in essence, opened the door for potential consideration of other innovative leak detection technologies or methods.

1.2 Bureau of Land Management (BLM)

1.2.1 BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation (43 CFR Parts 3100, 3160 and 3170)

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The BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation rule ("Waste Prevention rule") was proposed in 2016 and became effective on January 17, 2017. As of the publication of this document, the status of the Waste Prevention rule is uncertain (*note here or reference to current status).* However, a summary of the requirements as they currently stand will be provided. The rule includes LDAR requirements for existing and new facilities located on BLM-managed lands, which includes semi-annual leak monitoring at well sites (including oil wells that also produce natural gas and produced water handling facilities) and quarterly monitoring at compressor stations.

Alternative Technology Provisions

The Waste Prevention rule applies to hydrocarbon emissions (methane + VOCs) and, similar to NSPS OOOOa, allows for the use of OGI or Method 21 for leak monitoring, as well as approved alternatives. The rule specifies that any person may request approval of an alternative monitoring device and protocol (e.g. a device that monitors continuously, but is less sensitive than optical gas imaging, might achieve results equivalent to optical gas imaging due to the gas savings from early detection) by submitting a Sundry Notice to BLM that includes the following information:

(1) Specifications of the proposed monitoring device, including a detection limit capable of supporting the desired function;

(2) The proposed monitoring protocol using the proposed monitoring device, including how results will be recorded;

(3) Records and data from laboratory and field testing, including but not limited to performance testing;

(4) A demonstration that the proposed monitoring device and protocol will achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring;

(5) Tracking and documentation procedures; and

(6) Proposed limitations on the types of sites or other conditions on deploying the device and the protocol to achieve the demonstrated results.

The BLM may approve an alternative monitoring device and associated inspection protocol if the BLM finds that the alternative would achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring. The BLM will provide public notice of a submission for approval and may approve an alternative device and monitoring protocol for use in all or most applications (i.e. once approved, any operator could use it, which differs from NSPS OOOOa), or for use on a pilot or demonstration basis under specified circumstances that limit where and for how long the device may be used. The BLM will post on its web site a list of each approved alternative monitoring device and protocol, along with any limitations on its use. The BLM intends that the decision to approve the use of an alternative monitoring device would be made only at the national level, by the Director, Deputy Director, or an Assistant Director, as, once approved, the alternative monitoring device could be used at any facility subject to BLM requirements.

In addition to the alternative monitoring device option, the Waste Prevention rule also includes a provision for approval of an alternative instrument-based leak detection program. The BLM may approve an operator's request to use an alternative instrument-based leak detection program if the BLM finds that the alternative program would achieve equal or greater reduction of gas lost through leaks compared with OGI semiannual/quarterly monitoring. For example, an operator might propose a program that included more frequent inspections for some sites and less frequent inspections for others, or an operator may be able to deploy an alternative leak detection device or system, approved by the BLM, on a continuous basis and achieve results that would allow for less frequent inspections using optical gas imaging or Method 21. In essence, the alternative leak detection program allows for flexibility to potentially combine use of an alternative leak detection monitoring device with an already-approved monitoring device or method under the rule (OGI and Method 21).

The operator must submit its request for an alternative leak detection program through a Sundry Notice that includes the following information:

(1) A detailed description of the alternative leak detection program, including how it will use OGI and/or Method 21, along with sensory leak detection methods (audio/visual/olfactory or AVO), and an identification of the specific instruments, methods and/or practices and elements of the approach;

(2) The proposed monitoring protocol;

(3) Records and data from laboratory and field testing, including, but not limited to, performance testing, to the extent relevant;

(4) A demonstration that the proposed alternative leak detection program will achieve equal or greater reduction of gas lost through leaks compared to OGI or Method 21 with AVO semiannual/quarterly monitoring;

(5) A detailed description of how the operator will track and document its procedures, leaks found, and leaks repaired; and

(6) Proposed limitations on types of sites or other conditions on deployment of the alternative leak detection program.

Unlike the alternative monitoring device approval, a BLM State Director could approve an alternative leak detection program if the alternative program is determined to achieve equal or greater reduction of gas lost through leaks compared to the leak detection program required under the rule. However, the rule does not allow other operators to use an alternative leak detection program requested by and approved for a specific operator, as the results may not be transferable.

The BLM may also approve an alternative leak detection program if the operator demonstrates, and the BLM agrees, that compliance would impose such costs as to cause the operator to cease production and abandon significant recoverable oil or gas reserves under the lease. The operator must consider the costs and revenues of the combined stream of revenues from both the gas and oil components and provide the operator's projections of oil and gas prices, production volumes, quality (i.e., heating value and hydrogen sulfide content), revenues derived from production, and royalty payments on production over the next 15 years or the life of the operator's lease as part of the alternative leak detection program request.

Finally, the Waste Prevention rule also allows an operator to choose to comply with the EPA fugitive emissions monitoring requirements in NSPS OOOOa in lieu of complying with the LDAR provisions in the Waste Prevention rule for all sites and equipment not already deemed in compliance with the BLM LDAR provisions. This provision allows an operator with some facilities subject to NSPS OOOOa and the Waste Prevention rule and other facilities only subject to the Waste Prevention rule to apply a single leak detection regime to all of their facilities, rather than complying with NSPS OOOOa for some facilities and the BLM requirements for others.
If an operator decides to comply with NSPS OOOOa, they must also look for leaks on tank covers and closed vent systems (whose inspection requirements reside in a different part of OOOOa than the LDAR provisions)

As of the date of this document, the BLM State Director for New Mexico has approved the use of Tunable Diode Laser Absorption Spectroscopy (TDLAS) as part of an alternative instrument-based leak detection program *(need more details on this)*.

Federal Register Notice - [HYPERLINK "https://www.gpo.gov/fdsys/pkg/FR-2016-11-18/pdf/2016-27637.pdf?utm_campaign=subscription%20mailing%20list&utm_source=federalregister.gov&utm_medium=email"]

Commented [TTA8]: Need to check if other alt. tech/programs have been approved.

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1.3 Pipeline and Hazardous Material Safety Administration (PHMSA) - Federal Gas Pipeline Safety Regulations

The safety of natural gas pipeline systems are regulated by the United States Department of Transportation's (USDOT) Pipeline and Hazardous Material Safety Administration (PHMSA). PHMSA directly administers the pipeline safety program and develops and enforces requirements for interstate and intrastate pipelines. These regulations are written to ensure safety in the design, construction, testing, operation, and maintenance of pipeline facilities and in the siting, construction, operation, and maintenance of liquefied natural gas (LNG) facilities. PHMSA ensures compliance with regulations through operator inspections, enforcement actions, and accident investigations.

PHMSA also administers grant-in-aid funding to Statesthat provides reimbursement for up to 80% of qualified expenses incurred by the State program for pipeline inspection activities. Each participating State delegates responsibility for pipeline safety to a State agency. State agency duties normally consist of operator inspections, compliance and enforcement, safety programs, accident investigations, pipeline construction inspections, and record maintenance and reporting.

The State agency may adopt additional or more stringent standards for intrastate pipeline facilities provided such standards are compatible with Federal regulations.[1] Under an *agreement* or *interstate* agent agreement, the State agency assumes inspection responsibility for facilities and reports probable violations to PHMSA for compliance action.[2]

<u>1.3.1 PHMSA Natural Gas Pipeline Regulations</u>

PHMSA requires operators of pipeline facilities to follow regulations applicable to the commodity being transported. For natural gas, which is mostly methane, the requirements are found in Code of Federal Regulations 49 Part 192 (49 CFR Part 192) – Transportation of Natural and Other Gasses by Pipeline, and include leak monitoring or survey requirements, which will be discussed here.

An important aspect of the natural gas pipeline safety regulations is that for each operations and maintenance technical requirement found in Part 192, there must be a corresponding operator procedure for meeting that requirement. Operators are required to follow both the technical requirements found in Part 192 and the procedures it has developed for meeting those requirements, including leak monitoring and repair. It is also important to note that the requirements found in Part 192 are considered minimum requirements, meaning each operator can, and often does, have procedures that are more prescriptive and more stringent than the requirements found in Part 192.

<u>Operations and Maintenance</u>

Each pipeline operator is required to prepare and follow a manual of written procedures for conducting operations and maintenance activities for each pipeline, including leak monitoring and repair.

1 Each transmission line and distribution main must be surveyed at regular intervals for indications of leaks using leak detection equipment and hazardous leaks must be repaired promptly. *(Need explanation or definition here on what is considered a "hazardous leak").*

2 Compressor stations, pressure regulating stations, and valves along pipelines also need to be tested and inspected at regular intervals to ensure that the equipment is operating as designed and able to be used when needed. These testing and inspection activities normally include leak detection and repair.

<u>Leak Detection</u>

As noted, Part 192 requires leakage surveys be conducted using "leak detector equipment", which is a performance-based requirement, meaning that any equipment capable of detecting all leaks in gas distribution or transmission systems may be used. The regulations do not mandate the use of any specific type of leak detection equipment and since natural gas is primarily methane, equipment that can only detect methane is acceptable. However, it is imperative that procedures exist for proper use and calibration of the equipment. In addition, since State pipeline safety regulations are allowed to be more specific and more stringent than federal regulations, a state may adopt leak detection equipment requirements of its own for conducting leakage surveys in its specific jurisdiction.

Examples of acceptable natural gas pipeline leak detection equipment or methods include *(need examples here)…*

Another important aspect of pipeline safety related to leak surveys is integrity management (IM). Transmission and distribution operators are required to have IM programs to evaluate and address risks on their pipelines, which include using performance metrics to measure the number of hazardous leaks either eliminated or repaired, and the total number of leaks either eliminated or repaired, categorized by cause.

2. State Government Fugitive Emission/LDAR Regulations

In addition to federal requirements, some state governments have adopted their own fugitive emission/LDAR regulations for the oil and gas sector that supplement or go beyond federal requirements. Some of these regulations target or include methane and some do not. Additionally, some of the regulations allow for the approval of innovative or alternative leak detection technologies, while others mandate that only certain types of technologies or methods may be used. A summary of specific state fugitive emission/LDAR regulations is provided below.

ITRC conducted a survey of state and local governments concerning fugitive emission/LDAR regulations for the oil and gas sector that was coordinated by ITRC's state Point of Contacts (POCs). Information obtained through that survey helped inform what is included in this section.

2.1 State Government Regulations that apply to Fugitive Methane Emissions

2.1.1 California – Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (Air Resources Board)

California is unique among states to have the only oil and gas regulation focused exclusively on methane. California's "Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities" regulation, which became effective January 1, 2017 and requires full compliance by December 31, 2018, is aimed at reducing statewide methane emissions from new and existing facilities in the oil and gas production, processing, and storage sectors, and from transmission compressor stations. Its requirements include:

- Vapor collection on uncontrolled separators and tanks;
- Leak Detection and Repair (LDAR) at facilities not already covered by local air districts' VOC rules;
- LDAR monitoring at underground gas storage facilities, as well as ambient air monitoring and daily or continuous wellhead monitoring;
- Emissions standards for both reciprocating and centrifugal compressors, in addition to LDAR; and
- No-bleed requirements for pneumatic devices and pumps.

The statewide methane regulation's LDAR provision requires quarterly inspections using detection and measurement instruments compatible with US EPA Method 21, with the final leak standard being 1,000 ppmv. Currently, there is no alternative leak detection method or technology allowed, but the California Air Resources Board (CARB), which administers the rule, may consider allowing alternative methodologies in future amendments if, for example, Optical Gas Imaging technology evolves to allow quantification in addition to detection. However, the underground gas storage provision does allow for different and more innovative instrument technologies. This provision includes daily or continuous leak monitoring at the wellheads as well as ambient air monitoring and the use of OGI in the case of a well blowout.

California has eight oil and gas producing local air districts that have their own LDAR rules -- some for decades -- to reduce VOC emissions from oil and gas operations. California used these district VOC rules as a starting point for its methane regulation's LDAR provision. For the most part, the district and CARB LDAR provisions are similar, but there are some differences. For example, inspections may be less frequent in district rules, and the leak concentration standards vary. The district LDAR rules typically exempt components at oil and gas facilities that exclusively handle gas, vapor, or liquid with a VOC content of 10 percent by weight or less. It is these components that the CARB regulation covers. District VOC rules cover about 80 percent of all the components in the sector.

2.1.2 California – Oil & Gas Pipelines Requirements (Division of Oil, Gas & Geothermal Resources)

2.2 State Government Regulations or Permits that apply to Fugitive Methane + VOC Emissions

2.2.1 Colorado – Regulation No. 7 (Air Pollution Control Division)

In 2014 and 2017, Colorado's Air Quality Control Commission (AQCC) adopted updates to Regulation No. 7 that focus on reducing methane and VOC emissions from the upstream oil and gas sector, which includes well production facilities, natural gas compressor stations, and natural gas processing plants (https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_1.pdf). The regulation includes LDAR provisions for well production facilities and compressor stations that require one-time or periodic monitoring for leaks from components using an Approved Instrument Monitoring Method (AIMM), which may be OGI, EPA Method 21 or other Division-approved instrument based monitoring device or program ("alternative AIMM"). An alternative AIMM must be able to demonstrate it is capable of achieving comparable emissions reductions as OGI or Method 21. Section XII.L.8.a.(ii) specifies the information that must be provided for an alternative AIMM application, which is also identified in a guidance document developed for alternative AIMM applications by Colorado's Air Pollution Control Division (see below). If OGI is used as AIMM, a leak is defined as any detectable emissions observed using the OGI instrument. If Method 21 is used, a leak is defined as either a hydrocarbon concentration of 2,000 ppm or 500 ppm, depending on the facility type, when it was constructed and where it is located (NAA?).

There are also separate requirements specific to atmospheric storage tanks that store hydrocarbon liquids, which includes condensate, oil and produced water, known as Storage Tank Emission Management (STEM). STEM requires that all storage tank hydrocarbon emissions must be routed to air pollution control equipment. To help accomplish this, a STEM plan has to be developed and implemented to identify technologies, practices and strategies to prevent the release of tank emissions to atmosphere. Additionally, periodic AIMM monitoring and audio, visual and olfactory (AVO) inspections of affected tanks must be conducted to check for the release of emissions. Any detectable tanks emissions must be immediately addressed or repaired.

Updates to Regulation No. 7 in 2017 also require periodic AIMM inspections of gas-actuated pneumatic controllers to find and address controllers in need of repair, adjustment or replacement.

Colorado's Air Pollution Control Division ("APCD") has developed guidance and an application form for technologies or methods seeking to gain approval as AIMM under Regulation No. 7 ([HYPERLINK "https://www.colorado.gov/pacific/cdphe/AIMM"]). The guidance specifies that a technology or method must not be in the prototype or development phase in order be considered and may be approved as either a quantitative or non-quantitative AIMM. A quantitative AIMM must be able to detect and measure the hydrocarbons in the emissions stream, while a non-quantitative AIMM only needs to detect the hydrocarbons in the emissions stream. The criteria used for evaluating an

AIMM application include the operating requirements and limitations of the technology or method, including the emissions detection threshold and anything that impacts detectability, ability to pinpoint the specific source of emissions or leak location, calibration and maintenance requirements, data logging and recordkeeping capabilities, training or certification for use and operation, and testing results (lab and/or field), including any comparative monitoring with OGI and/or Method 21. If a technology or method is approved as AIMM, APCD issues an approval letter to the applicant that outlines the conditions or requirements for use of the AIMM and posts the approval letter on the APCD's AIMM web page. Once an AIMM is approved, it may be used by anyone to meet Regulation No. 7 requirements.

As of the date of this document, two technologies or methods had been approved as AIMM by APCD *(will need to update this accordingly)*.

2.2.2 Colorado – Pipeline & Flowline Safety Regulation (Oil & Gas Conservation Commission)

2.2.2 Pennsylvania – General Permit 5 and Permit-Exemption Category No. 38

Pennsylvania's General Permit 5 (GP-5) is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are that are classified as minor sources of air pollution.

GP-5 was first approved by the Pennsylvania Department of Environmental Protection (DEP) on February 1, 2013. ([HYPERLINK "http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf"]) An owner or operator of a facility subject to GP-5 must conduct monthly leak monitoring at the facility on a monthly basis using AVO methods and on a quarterly basis using an OGI camera or other leak detection monitoring device approved by the DEP. A leak is defined as any release of gaseous hydrocarbons detected by the OGI camera or through AVO methods.

Permit-exemption category no. 38 (PE #38) was finalized on August 10, 2013 and applies to unconventional wells, wellheads, and associated equipment and requires an LDAR program within 60 days after a well is put into production, and annually thereafter, as a condition of meeting the permit-exemption. The LDAR program must utilize an OGI camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2%, or other leak detection monitoring devices approved by the DEP. LDAR must be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquid service.

As of the date of this document, DEP has not published any guidance on the application and evaluation procedures for "other leak monitoring devices" to gain approval for use under GP-5 and PE #38. A Frequently Asked Questions (FAQ) document published by DEP for GP-5 and PE #38 states that an alternate leak detection technology could be used if "it is approved by DEP following a case-by-case evaluation of the device or

technology."
(http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/FAQ_GP-5_AND_EXEMPTION_CATEGORY_NO_38.pdf)

As of the date of this document, no requests for approval of alternate leak detection technologies or methods had been submitted to the DEP.

2.2.3 Ohio – General Permits 12.1, 12.2 and 18.1

The Ohio Environmental Protection Agency (OH EPA) approved two types of general permits for high volume horizontal hydraulic fracturing, oil and gas well site production operations (General Permits 12.1 and 12.2) in May 2014 and a general permit for equipment leaks from natural gas compressor stations (GP 18.1) in early 2017 ([HYPERLINK "http://www.epa.ohio.gov/dapc/genpermit/genpermits.aspx" \l "127854016-available-permits"])

Each of these permits require development and implementation of an LDAR program for equipment that has the potential to leak (pumps, compressors, pressure relief devices, connectors, valves, flanges, intermittent/snap-action pneumatic controller, vents, covers, any bypass in a closed vent system, and each storage vessel) using an OGI camera or EPA Method 21. Leak monitoring must be conducted within 60 or 90 days of startup and quarterly thereafter. GP 12.1 and 12.2 allow the monitoring frequency to be reduced after the first four quarters of monitoring if the leak rate of the equipment at a facility is determined to be less than 2.0%. A leak is defined as any detectable emissions with the OGI camera or concentrations between 500 – 10,000 ppm depending on the component if Method 21 is used.

2.2.4 New York regulations *(currently pending – check with Ona on status and any draft language)*

2.3 State Government Regulations or Permits that apply to Fugitive VOC Emissions

2.3.1 Utah – General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery

In June 2014, the Utah Department of Environmental Quality (UTDEQ)issued "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" (https://deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf).
This General Approval Order (GAO) requires LDAR for affected equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) at a well site and/or tank battery using OGI, EPA Method 21 or tunable diode laser absorption spectroscopy (TDLAS). Inspection or monitoring frequency is based on projected

throughput of crude oil and condensate in the storage tank(s) on site, or annually if no storage tanks are on site. The monitoring frequency may be reduced at sites with tanks that have large throughputs if no leaks are found over a certain period.

A leak is defined as a reading of 500 ppm with a Method 21 analyzer or TDLAS, or visible/detectable emissions with OGI.

Although the GAO does not specifically indicate that it covers methane emissions, UTDEQ estimated methane reductions that would be achieved through implementation of the GAO *(ref. "Comparison of State Leak Detection and Repair Programs, 4/20/16, EC/R Inc.).*

2.3.2 Wyoming – Air Quality Standards & Regulations, Chapter 8

In June 2015, the Wyoming Department of Environmental Quality (WYDEQ) finalized revisions to Chapter 8 of the Wyoming Air Quality Standards and Regulations (WAQSR). The revisions include a requirement in Section 6 for multiple or single well production facilities and all compressor stations with fugitive emissions greater than or equal to 4 tons per year of VOCs in existence prior to January 1, 2014 in the Upper Green River Basin ozone nonattainment area to develop and implement an LDAR program by January 1, 2017. Operators must monitor components quarterly using EPA Method 21, an OGI/IR camera, or other instrument based technology or method, along with AVO inspections.

The rule also requires that companies submit the protocols for their LDAR program to WYDEQ for approval. Thus, if the protocol includes a request to use an alternative instrument based monitoring method or technique besides Method 21 or an OGI/IR Camera, then WYDEQ could approve that if it deemed it to be acceptable.

As of the date of this document, no company has submitted an LDAR protocol to WYDEQ requesting the use of an alternative instrument based monitoring method or technique *(inquiry only submitted for TDLAS in June 2017; check w/Jeff Wendt at a later date to see if an official application/protocol request has been submitted).*

Per email 4/5/17 with Jeff Wendt, P.E., District Engineer, Wyoming Department of Environmental Quality, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

Commented [SS11]: Use this as our citation?

Commented [TTA12]: I don't think this is necessary to cite because the rule allows for use of an alternative instrument based monitoring technology if approved by WYDEQ via the LDAR protocol that has to be submitted and approved per the rule.

Wyoming regulations are available at http://soswy.state.wy.us/Rules/RULES/9868.pdf

3. International Methane Emission Regulations

Outside of the United States, a few other countries have adopted or are in the process of adopting regulations to reduce methane emissions from the oil and gas sector. The basis for these regulations is often to help meet commitments for greenhouse gas (GHG) reductions under international climate agreements. A summary of select countries with methane regulations or methane reduction requirements for the oil and gas industry is summarized below.

3.1 Canada

In Canada, federal regulations were proposed on May 27, 2017 to regulate hydrocarbon emissions from the upstream oil and gas sector. The requirements cover five main hydrocarbon (methane and VOC) emission sources, including leaks from equipment. The proposed regulations require LDAR three times per year at production sites, gas processing facilities, and transmission facilities. Operators must inspect equipment components three times per year using portable monitoring instruments or optical gas imaging instruments or an approved alternate leak detection technology. Approval for the use of the alternate technology will be granted at a facility level. Fast-tracked approvals are possible if any other jurisdiction has approved the use of the technology. Approvals are granted based on data collected by the operator over a 12 month period to show that the alternate leak detection technology is capable of detecting a leak of hydrocarbons that is detectable by an optical gas imaging instrument. The operator must also provide a description of the technology including detection limit, protocols for use, and repeatability. Final regulations are expected to be published by the end of 2017.

3.1.1 – Canadian Provinces

There are provincial directives in place to manage fugitive emissions, particularly in British Columbia and Alberta, where the majority of on-shore oil and gas activities are occurring. Saskatchewan, a major oil and gas producing province, has a directive in place to address venting, but does not address the management of fugitive emissions. The provincial directives are not entirely consistent and do not cover all sources of fugitive and venting emissions. Directives are generally considered non-binding and non-enforceable unless incorporated by reference in a regulation or permit. Permits issued by the provinces are site-specific authorizations for a specific activity or industry, and can vary in the type of sources covered and the stringency of requirements.

Voluntary measures:
The Canadian Association of Petroleum Producers (CAPP), an industry association, developed the voluntary *Best Management Practice: Management of Fugitive Emissions at Upstream Oil and Gas Facilities* (BMP) in 2007 for reducing fugitive emissions of methane and volatile organic compounds at oil and gas facilities. The BMP provides guidance for developing fugitive management programs which focus on areas most likely to offer significant cost-effective control opportunities (on specific component types and service applications), without providing firm time limits on inspection frequency or repair time. This BMP is referenced in British Columbia's *Flaring and Venting Reduction Guideline* and Alberta's *Directive 60* which state that facilities must develop and implement a program which "meets or exceeds the CAPP *Best Management Practice for Fugitive Emissions Management*". The CAPP BMP lists a number of methods that could be used to detect, measure or estimate leaks, and assesses qualitatively the effectiveness and approximate cost of these methods.

Commented [SS13]: Can we get entire citation?

Commented [RG14]: Available at [HYPERLINK "http://www.capp.ca/publications-and-statistics/publications/116116"] Publication # 2007-0003, published January 2007.

Proposed regulations:

The Alberta Energy Regulator (AER) proposes to release draft regulations for methane emission reduction in the upstream oil and gas sector. The regulations would cover fugitive emissions, requiring leak detection and repair, as well as measurement, monitoring and reporting. The regulations will be referenced by the directive D-60. Implementation may be in 2018 or later.

Commented [RG15]: As of August 2017, AER has not publicly released any further information about this proposal. Should we keep the reference to it here? I added this paragraph based on a news article found here: http://www.jwnenergy.com/article/2017/1/new-alberta-methane-emission-reduction-regulations-come-summer/

Commented [TTA16]: Yes, let's keep reference for now as that could change in the coming months.

3.2 Norway

According to the Norwegian Environmental Agency, "Methane emissions are covered by Norway's GHG reduction goals. Norway plans to reduce its global greenhouse gas emissions by the equivalent of 30 % of its own 1990 emissions by 2020. By 2030, Norway plans to reduce its GHG emissions by the equivalent of 40 % compared to the 1990 emissions." ([HYPERLINK "http://www.miljodirektoratet.no/en/Areas-of-activity1/Climate/Short-Lived-Climate-Pollutants/Key-regulations-and-goals-on-SLCPs-in-Norway/"]).

Norway regulates methane emissions from the oil and gas sector through several acts or laws, including the Pollution Control Act, Greenhouse Gas Emission Trading Act, CO_2 Tax Act (offshore) and the Petroleum Act. *(Try to obtain details on any possible LDAR requirements – contact NEA)*

3.3 Mexico

As a result of Mexico's participation in the United Nations Framework Convention on Climate Change, the state-owned oil company of Mexico, Petroléos Mexicanos (PEMEX), has taken steps to reduce methane emissions from its operations, including implementation of the Nationally Appropriate Mitigation Actions (NAMA) with the assistance of the British Embassy Prosperity Fund. The goal of NAMA is to reduce methane emissions in natural gas processing, transport, and distribution systems through periodic leak detection and repair (LDAR) activities. NAMA outlines both qualitative and quantitative methods for detecting leaks, including bubble tests, optical gas imaging (OGI), ultrasonic leak detectors, portable organic vapor analyzers, quantitative remote sensing techniques, and engineered estimates. PEMEX may also follow internationally recognized methods for leak identification, such as EPA Method 21.

3.4 Saudi Arabia

Saudi Arabia requires semi-annual LDAR inspections at oil and gas facilities that can be reduced to annual inspections if leaks are reduced. Facility operators must keep track of all leaks found and repaired and report them on an annual basis. Note, however, that the regulations do not outline proper leak detection methods or provide repair guidelines, therefore, operators can implement different methods and repair thresholds and timeframes.

3.5 Australia – New South Wales

The state of New South Wales in Australia has regulations to limit methane emission leaks from coal seam gas (CSG) operations. The regulations require CSG operators to develop and implement an LDAR program for their operations. Leak monitoring must be conducted in accordance with U.S. EPA Method 21 and U.S. EPA's Best Practices Guide for Leak Detection and Repair. (http://www.epa.nsw.gov.au/resources/epa/2564-methane-fact-sheet.pdf)